UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF OKLAHOMA

UNITED STATES OF AMERICA,

Plaintiff,

v.

OKLAHOMA GAS & ELECTRIC CO.,

Defendant.

Civil Action No. 5:13-cv-00690-D

PLAINTIFF UNITED STATES' OPENING BRIEF IN SUPPORT OF ITS MOTION FOR SUMMARY JUDEMENT AND DECLARATORY RELIEF

EXHIBIT 3-H

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

October 27, 2006

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AIR QUALITY

CERTIFIED MAIL 7004 0750 0000 9145 8479

Mr. Eddie Terrill, Division Director
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677

RE: Oklahoma Gas & Electric Co. Sooner Generating Station Unit 2 Steam Turbine Project and Boiler Surface Optimization

Dear Mr. Terrill:

Enclosed is a document titled "Air Quality Regulatory Applicability for Proposed Steam Turbine Project and Boiler Surface Optimization". The document identifies the applicable regulatory citations and discusses the methodology that was used to determine past actual and future projected actual emissions.

The Sooner project began on October 23, 2006. It is anticipated that the project will be completed and the unit restarted on December 18, 2006. Therefore, post-project emissions will be calculated from January 2007 through December 2007 and reported to ODEQ within 60 days after the end of 2007.

If you have any questions, please contact Laura Herron at 405.553.3057 or me at 405.553.3690.

Sincerely,

David Branecky

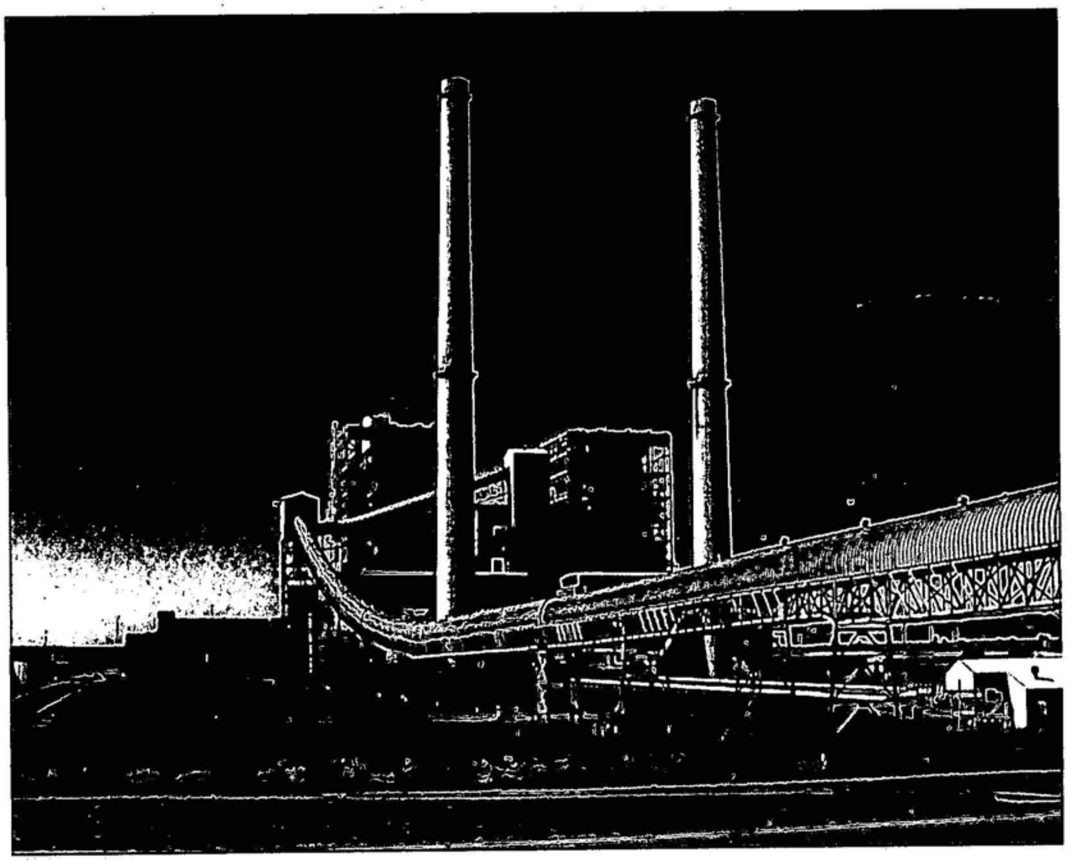
David Branecky
Manager Air Quality

Enclosure:

Cc: IXOS id 3722 J. Parham
F. Benham

AIR QUALITY REGULATORY APPLICABILITY
FOR
PROPOSED STEAM TURBINE PROJECT
AND
BOILER SURFACE OPTIMIZATION

OKLAHOMA GAS & ELECTRIC SOONER GENERATING STATION UNIT 2



October 27, 2006

SUMMARY

In order continue to provide a reliable source of electricity to our customers Oklahoma Gas & Electric Company (OG&E) finds it necessary to replace turbine HP/IP rotor, the last section of LP turbine blades and add additional heat transfer surface to the boiler on Sooner Generating Station Unit 2. This document determines potential emission impacts for the proposed project, the potential applicability to New Source Performance Standards (NSPS) and New Source Review (NSR), and sets forth OG&E's proposed plan of action for compliance. This project began on October 23, 2006 and is scheduled to be completed by December 18, 2006.

BACKGROUND & PROJECT DESCRIPTION

Sooner Power Plant consists of two separate coal-fired units (#1 and #2). Each of the coal units is nominally rated at approximately 570 MW generating capacity and has been in operation for approximately 25 to 30 years. Oklahoma Department of Environmental Quality (ODEQ) has issued a Title V operating permit for the facility as Permit number 2003-274-TVR. The unit under consideration has permit emission limits in terms of pounds of specific pollutant per million Btu. The Sooner Power Plant is located in Noble county, which is considered "in attainment" of the Federal air quality standards.

The Sooner Unit 2 General Electric steam turbine consists of a High Pressure (HP) section and an Intermediate Pressure (IP) section, and two double-flow Low Pressure (LP) sections. The turbine project will include replacement of the HP/IP rotor and replacement of the last row of LP turbine blades. The HP/IP rotor replacement provides an advanced design steam path intended to improve heat rate (efficiency) and power output. Replacement of the LP blades will also improve heat rate and power output due to improved design, but is also needed due to normal deterioration of the existing blades. An estimated 30 MW power improvement is predicted, with the same initial steam conditions.

The Sooner Unit 2 boiler will have additional heat transfer surface added to the superheat finishing section and reheat finishing section. The new advanced designed steam path turbine extracts more energy from the high pressure steam than the original turbine, leaving less energy in the cold reheat. In order to maintain design temperature of 1000 °F (final steam temperature) to the IP turbine section, additional heat transfer surface is necessary to absorb more heat. In the boiler flue gas stream, the superheat finishing section is arranged downstream of the reheat finishing section. With the additional heat transfer surface in the reheat finishing section, flue gas downstream of the reheat finishing section will become cooler. Subsequently additional heat transfer surface is necessary in the superheat finishing section to maintain steam temperature to the HP turbine section at 1000 °F, design temperature. Additional heat transfer surface must be added to the superheat and reheat finishing sections to obtain the full benefits of the new HP/IP turbine.

SUPPORTING DATA

- The project is scheduled for a unit overhaul during the period from October 23 to around December 18, 2006.
- The cost of the turbine project is approximately $8,733,000.
- The cost of the boiler optimization project is approximately $5,474,000.
- The original cost of construction of Unit 2 excluding siding, foundation, roof, and all other attachments was approximately $62,000,000.00 (1980 dollars).
- The purpose of this project is to minimize downtime, reduce potential safety hazards, and increase efficiency.
- Emission factors for Sooner Unit 2 (pulverized coal, dry bottom, tangentially fired boiler) are as follows:
    - CO = 0.5 lb/ton based on AP-42 Table 1.1-3 (9/98)
    - VOC = 0.06 lb/ton based on AP-42 Table 1.1-19 (9/98)
    - TSP = 0.048 lb/mmBtu per compliance test
    - PM_{10} = 0.03216 lb/mmBtu based on 67% of TSP per AP-42 table 1.1-6 (9/98)
    - NO_x actual emissions from Acid Rain CEMS
    - SO_2 actual emissions from Acid Rain CEMS
    - H_2SO_4 emissions based on SO_2 emissions and factors from Southern Company
    - Average heat content of coal = 8,771 Btu/lb

APPLICABLE AIR QUALITY REGULATIONS

New Source Performance Standards

The coal-fired unit in question is currently applicable to NSPS Subpart D. There is a possibility that the changes under consideration could be considered a "modification" [1] or "reconstruction" [2] and thus make the units applicable to Subpart Da.

"Modification" excludes "an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on the facility." A "capital expenditure" level is established in IRS Publication 534 (last listed in the 1984 edition) for each type of industry. The electric power generation industry is listed with a capital expenditure threshold of five percent. This has been interpreted to require the comparison of the capital cost of construction of the emissions unit (at time of construction) as compared with the cost of changes under consideration (present dollars). In this case the changes planned for Sooner Unit 2 boiler are estimated to cost a total of approximately $14,207,000. The past actual cost of construction of the Number 2 Unit was approximately $62,000,000.00 (1980 dollars). Thus, the proposed changes cost approximately 22.9 percent of the original cost. However, to be considered a modification, there must be an accompanying increase in the emission rate. The turbine project and the boiler surface optimization do not result in increased heat input and thus do not result in an increase in the hourly emission rate. Therefore, even though the project qualifies financially

[1] 40 CFR Part 60, paragraph 60.14
[2] 40 CFR Part 60, paragraph 60.15

as a modification; because the hourly emissions do not increase the unit will not be subject to Subpart Da.

"Reconstruction" under NSPS definitions includes changes whose "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." The costs of the changes under consideration are relatively minor compared to the cost of a new facility and thus the changes would not be considered a reconstruction under NSPS.

<u>New Source Review</u>

Whether or not physical changes to equipment at existing power plants trigger New Source Review (NSR) permitting requirements can be a complicated and controversial issue. The Prevention of Significant Deterioration (PSD) program is the NSR permitting mechanism for projects that occur in areas that are in attainment of the National Ambient Air Quality Standards (NAAQS). Traditionally, assessing PSD applicability for a physical change to an existing emission unit at a power plant is a two-step process. First, emission increases from the proposed project are determined on a pollutant-by-pollutant basis and compared to the relevant Significant Emission Rates (SER). If the emission increase after the first step does not exceed the applicable SER, the project does not trigger PSD permitting requirements for that pollutant. For individual pollutants that do exceed the relevant SER, the second step requires a netting analysis. A netting analysis involves a determination of creditable contemporaneous period. With respect to "electric utility steam generating units," the Wisconsin Electric Power Company (WEPCO) series of court opinions, regulations, and guidance documents establish a framework within which a regulated party can calculate emission increases by which *past actual* emissions are subtracted from expected *future actual* emissions.

EMISSION CALCULATION METHODOLOGY

Baseline actual emissions for Sooner Unit 2 were determined as defined by 40 CFR 52.21(b)(48) which says, "Baseline actual emissions means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section". In addition, 40 CFR 52.21 (b)(48)(i) says, "For any existing electric utility steam generating unit, baseline actual emissions means the average rate in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction for the project…".

Projected actual emissions for Sooner Unit 2 were determined as defined by 40 CFR 52.21(b)(41)(i) which says, "Projected actual emissions means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project,…". 40 CFR 52.21(b)(41)(ii)(c) says that in determining projected actual emissions under paragraph (b)(41)(i), the owner or operator of the major stationary source,

"Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth."

For Sooner Unit 2, 40 CFR 52.21(r)(6)(iii) and (iv) will be followed to demonstrate future actual emissions. 40CFR 52.21(r)(6)(iii) says, "The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(b) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated NSR pollutant at such emissions unit." 40 CFR 52.21(r)(6)(iv) says, "If the unit is an existing electric utility steam generation unit, the owner or operator shall submit a report to the Administrator within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report."

Therefore, if Sooner Unit 2 resumes regular operating as scheduled during December 2006, emissions will be calculated from January 2007 through December 2007 and reported to ODEQ within 60 days after the end of 2007. The final emissions report for this project will be due 60 days after the end of 2011.

EPA Region 5 has further clarified the WEPCO decision by a letter (Appendix A) concerning the Detroit Edison Company dated May 23, 2000. Detroit Edison planned to conduct a turbine components replacement. EPA concluded that the replacement could not be considered routine but could be exempt from PSD consideration as long as there was not a significant increase of emissions. The letter also reaffirms the exclusion from consideration of emission increases "...which could have been accommodated before the change and is unrelated to the change, such as demand growth."

To verify that a significant increase of emissions would not occur, the EPA letter required Detroit Edison to provide project information to the local regulatory agency (Michigan DEQ) as listed below.

1. Calculation of past actual to future actual emissions comparison.
2. Annual reports for at least five years demonstrating that the renovation did not result in a significant emission increase (40 CFR 52.21(21)(v)).

EMISSIONS IMPACT OF THE PROJECT

Past actual emissions for Sooner Unit 2 for the previous 5 years have been collected through the Acid Rain Continuous Emissions Monitoring System (CEMS) and emissions calculations. This data is summarized in Appendix B. The data was reviewed to find the 24-month rolling period

with the highest activity/emission rates. This period of time was determined separately for each measure of activity: heat input, stack flow, SO_2 emissions and NO_x emissions. The highest activity rate for heat input derived emissions was determined to be during the 24-month block ending at the end of August 2006. Table 4-1 shows the allowable increase in emissions that would not be subject to PSD requirements. This analysis is based on the "past actual to future actual" test. If the proposed project increases emissions more than the allowable limit, excluding increases due to system generation demand growth, then the unit would be subject to PSD for that specific pollutant.

TABLE 4-1. ALLOWABLE EMISSIONS FOR PROJECT

Pollutant	Past Actual (tpy)	SER (tpy)	Projected Future Actual (tpy)
PM_{10}	613.9	15	628.8
SO_2	9,761.2	40	9,801.1
NO_x	6,595.3	40	6,635.2
VOC	65.3	40	105.2
CO	544.1	100	644
H_2SO_4	9.4	7	16.3

Notes:

1. Past actual emissions of SO_2 and NO_x based on Acid Rain CEMS (Maximum annual average from a 24 month period in past 5 years).
2. Past actual emissions of PM_{10}, VOC, and CO based on coal usage (heat input 38,179,055.9 MMBtu/yr) (Maximum annual average from a 24 month period in past 5 years) and AP42 (9/98) Chapter 1.1 emission factors. Average heat content of coal burned was 8,771 Btu/lb.
3. Sulfuric Acid emissions based on SO_2 emissions and factors developed by Southern Company. E1' (emission rate, lb/yr) = K (MW and units constant) * F1 (fuel impact factor) * F2 (technology impact factor) * E2 (SO2 emissions, tpy).
4. Projected future actual does not include increases from system generation demand growth.

Significantly, any increases of facility operations or emissions that are attributable to increased customer demand are not considered as increases for PSD evaluation. This exemption is clearly supported in the WEPCO and Detroit Edison decisions.

Therefore, in calculating future actual emissions for compliance demonstration purposes emission changes associated with increased utilization (but not associated with the proposed project, e.g. generation demand) are not included. The WEPCO rule expressly excludes from relevance any increase in emissions that are attributable to increased capacity utilization due to future system demand growth or the utility system. In addition, the future actual test period will be limited to five years.

PROPOSAL

OG&E proposes to limit emissions (excluding increases due to system generation demand (40 CFR § 52.21(b)(33)(ii)) on Unit 2 after the turbine project and boiler surface optimization such that the emission increase will not exceed the PSD significant threshold increase level. OG&E will maintain and submit to ODEQ on a calendar year basis for a period of five years starting with the first full calendar year after the date the unit resumes regular operation, information demonstrating that the turbine project did not result in an emissions increase.

APPENDIX A

U.S. EPA REGION V LETTER

May 23, 2000

R-19J

Henry Nickel
Counsel for the Detroit Edison Company
Hunton & Williams
1900 K Street, N.W.
Washington D.C. 20006-1109

Dear Mr. Nickel:

I am responding to your request on behalf of the Detroit Edison Company for an applicability determination regarding the proposed replacement and reconfiguration of the high pressure section of two steam turbines at the company's Monroe Power Plant, referred to as the Dense Pack project. Specifically, you requested that the United States Environmental Protection Agency (EPA) determine whether the Dense Pack project at the Monroe Power Plant would be considered a major modification that would subject the project to pollution control requirements under the Prevention of Significant Deterioration (PSD) program.

We have reviewed your original request, dated June 8, 1999, and the supplemental information you submitted on December 10, 1999, and March 16, 2000. We provisionally conclude that the Dense Pack project would not be a major modification. Thus, Detroit Edison may proceed with the project without first obtaining a PSD permit. Although the Dense Pack project would constitute a nonroutine physical change to the facility that might well result in a significant increase in air pollution, Detroit Edison asserts that emissions will not in fact increase due to the construction activity, and EPA has no information to dispute that assertion.

As you know, nonroutine changes of any type, purpose, or magnitude at an electric utility steam generating unit -- ranging from projects to increase production efficiency to even the complete replacement of entire major components -- are excluded from PSD coverage as long as they do not significantly increase emissions from the source. Thus, Detroit Edison has been free to proceed at any time with the Dense Pack project without first obtaining a PSD permit as long as it adheres to its stated intention to not increase emissions as a result of the project. Indeed, EPA encourages the company to proceed with the project on this basis, since it appears to both reduce emissions per unit of output and not increase actual air pollution.

As you are also aware, under the applicable new source review regulations, in determining if a physical change will result in a significant emissions increase at an electric utility plant, companies may use an "actual" to "representative actual annual emissions" test for emissions from the electric utility steam generating unit, under which a calculation of baseline emissions and a projection of future emissions after the change is needed. Our determination of nonapplicability is provisional because Detroit Edison has not, to our knowledge, provided a calculation of baseline emissions or projected future emissions to the permitting agency, and this should be done prior to the start of construction. The basis for this determination is summarized below and is set forth in full in the enclosed detailed analysis.

In determining whether an activity triggers PSD, the Clean Air Act and EPA's regulations

specify a two-step test. The first step is to determine if such activity is a physical or operational change, and if it is, the second step is to determine whether emissions will increase because of the change. The statute admits of no exception from its sweeping scope, but EPA's regulations contain some narrow exceptions to the definition of physical or operational change. In particular, Detroit Edison claims that the Dense Pack project is eligible for the exclusion for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors. After carefully reviewing all the information you submitted in light of the relevant factors, EPA has determined that the proposed project is not "routine."

The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Accordingly, because increasing turbine efficiency by a total redesign of a major component is a defining feature of the proposed Dense Pack project, it clearly goes significantly beyond both historic turbine work at Detroit Edison, and what would otherwise be considered a regular, customary, or standard undertaking for the purpose of maintaining the existing steam turbine units. The project also goes well beyond routine turbine maintenance, repair, and replacement activities for the utility industry in general.

The nature and extent of the work in question -- replacement of the entire high pressure sections of the steam turbines for Units 1 and 4 at Monroe -- suggests that the Dense Pack project is not routine. It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity. Accordingly, the proposed project represents a significant and major redesign and replacement of the entire high pressure sections of the steam turbines at Units 1 and 4 at the Monroe facility.

The frequency with which utilities have undertaken turbine upgrades like the Dense Pack project also indicates the nonroutine nature of the changes. The information provided by Detroit Edison, regarding past history at the Monroe facility, describes what is characterized as necessary maintenance, repair, and replacement of deteriorated turbine blades approximately every 4 years. During these overhaul periods, it is not uncommon for the company to replace up to several turbine blades at one time. It is common among other utilities to also perform similar turbine maintenance. However, Detroit Edison has not provided any information to suggest that a complete replacement and redesign of the high pressure section of a steam turbine is conducted frequently at Monroe or at any other individual utility. Instead, Detroit Edison relies on its claim that projects "similar" to the Dense Pack project have been performed at a number of utilities. This information does not indicate that the replacement of the high pressure section of the steam turbine is frequent at the typical utility source; to the contrary, the only available information

reflects that projects like the Dense Pack project have been performed only one time, if ever, at individual sources.

The cost of the Dense Pack project is significant and tends to indicate that this project is nonroutine. Detroit Edison expects the Dense Pack replacement to cost approximately $6 million for each turbine unit, for a total of $12 million. The EPA has rejected claims of routineness in past cases where the cost was substantially less than this figure. Moreover, Detroit Edison intends to capitalize the entire cost of this project, and EPA believes that a $12 million project that is 100 percent capital improvement indicates that it is a major undertaking.

Beyond the clearly significant absolute cost of this project, available information suggests that this expenditure far exceeds the cost typically associated with turbine blade maintenance activity. Detroit Edison provided only a summary of the total project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than $1 million to a little more than $6 million. Although Detroit Edison did not provide any detail regarding what specific activities comprise these aggregated amounts, it acknowledges that it spent only $18,700, $33,100, and $7,900 to replace high-pressure rotors in three turbine projects in 1981 and 1982. Further, the project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project. Accordingly, it appears that the costs associated with the Dense Pack project greatly exceed the amounts spent previously by Detroit Edison or that it would spend presently for the replacement of deteriorated turbine blades or rotors.

For the reasons delineated above, we conclude that the changes proposed by Detroit Edison are not routine. Detroit Edison's submissions do not demonstrate that projects such as the Dense Pack project are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Instead, the source relies on two principal arguments: (1) it claims that this project is less significant in scope than was the activity in question in the 1988 applicability determination for the Wisconsin Electric Power Company (WEPCO); and (2) it alleges that EPA has interpreted the exclusion for routine activity expansively to exempt all projects that do not increase a unit's emission rate. EPA rejects both of these arguments, the former because both EPA and the U.S. Court of Appeals for the Seventh Circuit viewed WEPCO's activity as "far from" routine and thus this attempted comparison to WEPCO is unsuitable, and the latter because it is demonstrably incorrect. The attached analysis addresses these points in significant detail.

When nonroutine physical or operational changes significantly increase emissions to the atmosphere, they are properly characterized as major modifications and are subject to the PSD program. In general, a physical change in the nature of the Dense Pack project, which provides for the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels. Even a small increase over current normal levels in the utilization of the affected units would result in a significant increase in actual emissions of criteria pollutants. For example, in 1997, at the Monroe facility Unit 1 emitted approximately

14,000 tons of nitrogen oxides (NOx) and 41,000 tons of sulfur dioxide (SO2), and Unit 2 emitted 12,000 tons of NOx and 35,000 tons of SO2. Based on this information, if a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NOx and 400-2000 tons of SO2 would occur.

Detroit Edison, however, maintains that emissions will not increase as a result of the Dense Pack project. Specifically, the company contends that representative actual annual emissions following the change will not be greater than its pre-change actual emissions, because the Dense Pack upgrade will not result in increased utilization of the units. As you are aware, the PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. In projecting post-change emissions, Detroit Edison does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth.

Under the WEPCO rule, Detroit Edison must compute baseline actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change (or another 2-year period that is more representative of normal operation in the unit's modified state). As noted above, Detroit Edison has not provided these figures to verify its projection of no increase in actual emissions, and should submit them to the Michigan Department of Environmental Quality prior to beginning construction. In addition, Detroit Edison must maintain and submit to the permitting agency on an annual basis for a period of at least 5 years (or a longer period not to exceed 10 years, if such a period is more representative of the modified unit's normal post-change operations) from the date the units at the Monroe Plant resume regular operation, information demonstrating that the renovation did not result in a significant emissions increase. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

Finally, regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison must meet all other applicable federal, state, and local air pollution requirements.

This determination will be final in 30 days unless, during that time, Detroit Edison seeks to confer with or appeal to the Administrator or her designee regarding it. If you have any questions regarding this determination, please contact Laura Hartman, Environmental Engineer, at (312) 353-5703, or Jane Woolums, Associate Regional Counsel, at (312) 886-6720.

Sincerely,

/s/

Francis X. Lyons
Regional Administrator

Enclosure

cc: Peter Marquardt, Esq., Special Counsel
Detroit Edison Company
2000 Second Avenue - 688 WCB
Detroit, Michigan 48336

Russell Harding, Director
Michigan Department of Environmental Quality

ACID RAIN CEMS DATA AND ANNUAL AVERAGES

Year-Month	HI (mmBtu)	SO2 (tons)	NOx (tons)	Avg SO_2[1] (tons)	Avg NO_x[1] (tons)	Avg HI[1] (mmBtu)	Avg VOC[1]	Avg CO[1]	Avg PM10[1]	Avg H_2SO_4[1]
10-2001	3,234,488	913.54	495.37							
11-2001	3,203,266	930.92	497.75							
12-2001	3,556,304	1,024.05	603.11							
01-2002	3,165,344	947.49	523.35							
02-2002	0	0.00	0.00							
03-2002	0	0.00	0.00							
04-2002	728,236	199.35	115.21							
05-2002	3,345,956	893.27	556.30							
06-2002	3,126,483	788.91	568.16							
07-2002	3,341,851	914.69	593.45							
08-2002	2,703,855	684.69	443.20							
09-2002	3,422,098	875.97	563.41							
10-2002	3,397,939	770.63	536.31							
11-2002	3,169,057	806.27	483.25							
12-2002	3,458,133	867.19	555.25							
01-2003	3,181,150	801.57	472.63							
02-2003	2,929,038	702.29	400.76							
03-2003	3,480,717	745.93	479.19							
04-2003	3,669,022	838.07	521.04							
05-2003	3,995,473	905.10	500.47							
06-2003	3,683,494	866.96	502.00							
07-2003	3,541,718	926.86	528.77							
08-2003	2,454,139	558.52	341.58							
09-2003	2,954,941	792.96	438.47	8,877.61	5,359.5	34,871,350.70	59.6	497.0	560.7	8.57
10-2003	3,701,462	951.34	580.26	8,896.51	5,402.0	35,104,837.84	60.0	500.3	564.5	8.6
11-2003	2,593,164	645.28	358.11	8,753.69	5,332.1	34,799,786.69	59.5	495.9	559.6	8.4
12-2003	3,854,072	602.16	602.16	8,542.75	5,331.7	34,948,670.89	59.8	498.1	562.0	8.2
01-2004	3,206,717	742.38	500.47	8,440.19	5,320.2	34,969,356.96	59.8	498.4	562.3	8.1
02-2004	1,569,945	383.03	195.11	8,631.70	5,417.8	35,754,329.59	61.1	509.6	574.9	8.3
03-2004	0	4.27	0.00	8,633.84	5,417.8	35,754,329.59	61.1	509.6	574.9	8.3
04-2004	533,337	135.37	83.49	8,601.85	5,401.9	35,656,880.24	61.0	508.2	573.4	8.3
05-2004	2,356,117	649.92	431.49	8,480.18	5,339.5	35,161,960.51	60.1	501.1	565.4	8.2
06-2004	2,912,040	820.82	582.63	8,496.14	5,346.7	35,054,739.25	59.9	499.6	563.7	8.2
07-2004	3,777,489	1,064.61	676.44	8,571.10	5,388.2	35,272,558.38	60.3	502.7	567.2	8.3

[1] Annual Average in tons from previous 24 months

2006 Baseline Sooner Unit 2

Year-Month	HI (mmBtu)	SO2 (tons)	NOx (tons)	Avg SO_2[1] (tons)	Avg NO_x[1] (tons)	Avg HI[1] (mmBtu)	Avg VOC[1]	Avg CO[1]	Avg PM10[1]	Avg H_2SO_4[1]
08-2004	3,685,835	1015.45	577.11	8,736.5	5,455.2	35,763,548.1	61.2	509.7	575.1	8.4
09-2004	3,916,758	864.63	687.49	8,730.8	5,517.2	36,010,877.9	61.6	513.2	579.1	8.4
10-2004	3,260,808	843.13	520.04	8,767.1	5,509.1	35,942,312.7	61.5	512.2	578.0	8.5
11-2004	3,823,805	1001.46	694.58	8,864.7	5,614.8	36,269,686.8	62.0	516.9	583.2	8.6
12-2004	4,232,773	1062.00	805.11	8,962.1	5,739.7	36,657,006.6	62.7	522.4	589.4	8.6
01-2005	3,947,688	1030.08	647.75	9,076.3	5,827.3	37,040,275.6	63.3	527.9	595.6	8.8
02-2005	2,708,913	660.79	498.26	9,055.6	5,876.0	36,930,213.0	63.2	526.3	593.8	8.7
03-2005	3,573,108	789.37	584.87	9,077.3	5,928.8	36,976,408.6	63.2	527.0	594.6	8.8
04-2005	934,734	205.61	146.02	8,761.1	5,741.3	35,609,264.7	60.9	507.5	572.6	8.5
05-2005	1,834,265	384.64	315.77	8,500.8	5,649.0	34,528,660.9	59.1	492.1	555.2	8.2
06-2005	3,119,880	790.47	535.19	8,462.6	5,665.6	34,246,854.2	58.6	488.1	550.7	8.2
07-2005	3,289,164	847.47	512.48	8,422.9	5,657.4	34,120,577.6	58.4	486.3	548.7	8.1
08-2005	2,782,707	661.18	409.60	8,474.2	5,691.4	34,284,861.4	58.6	488.6	551.3	8.2
09-2005	3,520,318	874.18	577.16	8,514.8	5,760.8	34,567,549.6	59.1	492.6	555.8	8.2
10-2005	3,233,775	810.94	524.77	8,444.6	5,733.0	34,333,705.8	58.7	489.3	552.1	8.1
11-2005	2,494,406	641.96	389.13	8,443.0	5,748.5	34,284,326.8	58.6	488.6	551.3	8.1
12-2005	2,466,936	693.94	460.49	8,488.9	5,677.7	33,590,758.8	57.4	478.7	540.1	8.2
01-2006	2,705,502	640.31	447.39	8,437.8	5,651.2	33,340,151.4	57.0	475.1	536.1	8.1
02-2006	3,283,894	913.07	646.27	8,702.9	5,876.8	34,197,125.7	58.5	487.4	549.9	8.4
03-2006	3,607,289	1048.16	792.32	9,224.8	6,272.9	36,000,770.5	61.6	513.1	578.9	8.9
04-2006	3,493,721	1013.33	671.34	9,663.8	6,566.8	37,480,962.3	64.1	534.2	602.7	9.3
05-2006	2,909,898	734.47	488.47	9,706.0	6,595.3	37,757,853.3	64.6	538.1	607.1	9.4
06-2006	3,614,236	931.13	571.56	9,761.2	6,589.8	38,108,951.3	65.2	543.1	612.8	9.4
07-2006	3,766,503	1011.39	611.56	9,734.6	6,557.3	38,103,458.3	65.2	543.0	612.7	9.4
08-2006	3,837,030	1049.53	635.36	9,751.6	6,586.5	38,179,055.9	65.3	544.1	613.9	9.4
09-2006	2,851,196	783.73	491.73	9,711.2	6,488.6	37,646,274.9	64.4	536.5	605.4	9.4
Maximum Annual Average				9,761.2	6,595.3	38,179,055.9	65.3	544.1	613.9	9.4

[1] Annual Average in tons from previous 24 months